April 30, 2004

EA 04-084

Mr. George Vanderheyden
Vice President - Calvert Cliffs Nuclear Power Plant
Constellation Generation Group, LLC
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657-4702

SUBJECT: CALVERT CLIFFS NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000317/2004004 AND 05000318/2004004

Dear Mr. Vanderheyden:

On March 31, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Calvert Cliffs Nuclear Power Plant Units 1 & 2. The enclosed report documents the inspection findings which were discussed on April 8, 2004, with members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents two self-revealing findings of very low safety significance (Green) which were determined to involve violations of NRC requirements. However, because of the very low safety significance and because the issue was entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCV) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation, which was determined to be of very low safety significance is listed in this report. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN. Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, Region 1; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Calvert Cliffs Facility.

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by the order. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during calendar year 2002, and the remaining inspection activities for Calvert Cliffs were completed in July 2003. The NRC will continue to monitor overall safeguards and security controls at Calvert Cliffs.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web Site at http://www.nrc.gov/reading-rm.html (the Public Electronic Reading Room).

Sincerely,

/RA/

James M. Trapp, Chief
Projects Branch 1
Division of Reactor Projects

Docket Nos.: 50-317, 50-318
License Nos.: DPR-53, DPR-69

Enclosure: Inspection Report 05000317/2004004 and 05000318/2004004
w/Attachment: Supplemental Information

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REGION I

Docket Nos.:	50-317, 50-318
License Nos.:	DPR-53, DPR-69
Report Nos.:	05000317/2004004 and 05000318/2004004
Licensee:	Calvert Cliffs Nuclear Power Plant, Inc. (CCNPPI)
Facility:	Calvert Cliffs Nuclear Power Plant
Location:	1650 Calvert Cliffs Parkway Lusby, MD 20657-4702
Dates:	January 1, 2004 - March 31, 2004
Inspectors:	Mark A. Giles, Senior Resident Inspector Joseph M. O'Hara II, Resident Inspector John R. McFadden, Health Physicist Thomas Burns, Reactor Inspector Nancy McNamara, Emergency Preparedness Inspector Neil Perry, Senior Project Engineer Suresh Chaudhary, Reactor Inspector
Approved by:	James Trapp, Chief Projects Branch 1 Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000317/2004004, 05000318/2004004; 1/1/2004-3/31/2004; Calvert Cliffs Nuclear Plant, Units 1 and 2; Maintenance Effectiveness, Identification and Resolution of Problems.

The report covered a three month period of inspection by resident inspectors and announced regional inspections including: an emergency preparedness inspector, a senior project engineer, two reactor inspectors, and a health physicist. The inspection identified two Green findings, which were determined to be non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, which requires that measures shall be established to assure significant conditions adverse to quality are promptly identified and corrected. Specifically the licensee failed to promptly identify a significant condition adverse to quality associated with the #10 upper crankcase bearing on the 2A Emergency Diesel Generator (EDG). This condition if left uncorrected could have resulted in the failure of the EDG. This degraded condition occurred in 1995 and again in October 2003, on the 2A EDG. As a result of the October 2003 degraded condition, the licensee requested a Notice of Enforcement Discretion (NOED) since repair activities would exceed the allowable outage times as specified in Technical Specification (T.S.) 3.8.1, "A.C. Sources - Operating." The NRC granted an NOED to the licensee on October 10, 2003.

This finding is greater than minor because it affects the Reactor Safety, Mitigating Systems attribute of equipment performance, and the availability, reliability, and capability objective of the mitigating systems cornerstone. If left uncorrected, this condition could have led to the failure of the 2A EDG. This finding was of very low safety significance because the degraded condition did not result in an actual failure of the EDG to perform its safety function. The inspectors identified that a contributing cause of this finding was related to the cross-cutting area of Problem Identification and Resolution. (Section 1R12)

Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, which requires that measures shall be established to assure significant conditions adverse to quality are promptly identified and corrected. Specifically, the licensee failed to implement effective corrective actions for significant conditions adverse to quality associated with component mispositioning events. A similar failure was first identified as NCV 05000317; 05000318/2003009-01 and documented in NRC Inspection Report IR-2003-009, issued November 7, 2003. Since then, two additional significant component mispositioning events occurred between

October 29, 2003, and March 31, 2004 both resulting in actual consequences to safety-related systems.

This finding is greater than minor because it affects the Reactor Safety, Mitigating Systems attribute of human performance, and the availability, reliability, and capability objective of the mitigating systems cornerstone. This finding was of very low safety significance because none of the events resulted in the actual loss of a system safety function. The inspectors identified that a contributing cause of this finding was related to the cross-cutting area of Problem Identification and Resolution. (Section 4OA2)

B. Licensee-Identified Violations

One violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation is listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent reactor power and remained unchanged until January 31, when power was reduced to about 67 percent for a brief period of time to support planned modifications on the 11 and 12 steam generator feedwater pump digital feedwater control systems. Following the modification, the unit remained at 100 percent reactor power until March 20, when a reactor trip occurred due to an induced ground which was caused during the performance of maintenance activities. Following repair activities, the unit was returned to 100 percent reactor power and remained there until March 30 when a rapid power reduction was performed to accommodate the potential impact from a fire protection system actuation. The unit achieved 100 percent reactor power the following day and remained there the rest of the inspection period.

Unit 2 began the inspection period at 100 percent reactor power and remained there until a reactor trip occurred on January 23, due to the tripping of the 22 steam generator feedwater pump. The unit achieved 100 percent reactor power on January 25, and remained there until March 14, when power was reduced to about 68 percent to support the recovery of a dropped control element assembly. Following this recovery action, reactor power was increased to 100 percent and remained there until the inspection period ended.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

1. Partial System Walkdown

a. Inspection Scope (71111.04Q - 3 samples)

The inspectors verified that select equipment trains of safety-related and risk significant systems were properly aligned. The inspectors reviewed plant documents to determine the correct system and power alignments, and the required positions of critical valves and breakers. The inspectors verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or potentially impact the availability of associated mitigating systems. The applicable documents for this inspection are located in the Attachment. The inspectors performed partial system walkdowns for the following systems:

- 12 Charging Pump (motor replacement)
- 23 Charging Pump (packing replacement and gearbox replacement)
- Chemical and Volume Control (2CVC-348 discharge drain valve replacement)

b. Findings

No findings of significance were identified.

2. Complete System Walkdown (Semi-Annual)

a. Inspection Scope (71111.04S - 1 sample)

The inspectors conducted a complete walkdown of the risk significant salt water system. The inspectors determined the correct system lineup using OI-29, Attachment 1, Saltwater System Valve Alignment, Attachment 2, Saltwater System Instrumentation Valve Alignment, and the appropriate piping and instrument drawings. Additionally, the inspectors reviewed outstanding design issues, temporary modifications, maintenance rule status, operator workarounds, and outstanding maintenance work requests and deficiencies that could affect the ability of the system to perform its functions. During the walkdown inspection, the inspectors verified the following: valves were correctly positioned and did not exhibit conditions which would impact their function; electrical power was available as required; labeling was correct; hangers and supports were correctly installed and functional; support systems were operational; valves required to be locked were properly locked; and there were no objects located such that they would interfere with system operation. Minor issues identified by the inspectors were provided to system engineering personnel.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

1. Fire Brigade Observation (71111.05A - 2 samples)

a. Inspection Scope

The inspectors observed a fire brigade drill conducted on February 27, 2004, involving a simulated fire in the Unit 2, 45 foot elevation west penetration room. The inspectors observed the brigade members donning protective equipment, transitioning to the scene of the fire, and fighting the simulated fire. The inspectors observed the fire brigade leader performing an assessment of the fire, communicating with team members and the control room supervisor, and directing the actions of the brigade to extinguish the fire. The inspectors attended the post drill debriefing between the assessment team and the fire brigade members. Constellation procedure SA-1-101, Fire Fighting, was referenced for this inspection activity.

On February 20, 2004 during a general plant tour, the inspectors noticed a small trash fire between a large dumpster full of combustible material and the loading dock behind the North Service Building. The inspectors reported the fire to the Unit 1 control room supervisor. In response, the plant fire alarm was sounded, and the fire brigade responded and quickly extinguished the fire with water. The area was raked clean of debris, and the dumpster was inspected to ensure the fire had not spread. Based on the possibility that the fire was started by an errant cigarette, the licensee posted the area as a “non-smoking” area.

b. Findings

No findings of significance were identified.

2. Fire Area Walkdowns (71111.05Q - 7 samples)

a. Inspection Scope

The inspectors walked down accessible portions of the plant to assess the licensee's control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures. The inspectors assessed the material condition of fire protection suppression and detection equipment to determine whether any conditions or deficiencies existed which could impair the operability of that equipment. The inspectors reviewed administrative procedure SA-1-100, Fire Prevention, during the conduct of this inspection. The inspectors toured the following areas important to reactor safety:

- Unit 1 West Electrical Penetration Room
- Unit 1 East Electrical Penetration Room
- Unit 2 Component Cooling Water Pump Room
- Unit 1 Component Cooling Water Pump Room
- Unit 1 Turbine Auxiliary Feedwater Pump Room
- Unit 2, "B" Emergency Diesel Generator Room
- Unit 1, 11, 12, and 13 Charging Pump Room Area

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (IP 71111.07B - 3 samples)

a. Inspection Scope

The inspectors reviewed licensee programs and processes to ensure that the following system components could perform their design functions as intended:

- Shutdown cooling heat exchangers for both units
- Containment coolers for both units
- Station blackout and emergency diesel generator jacket water and lube oil coolers

The shutdown cooling heat exchangers (HXs) are used to remove decay heat and reactor coolant sensible heat during plant cooldowns and cold shutdowns. The HXs also cool containment spray water during containment spray system operation. The shutdown cooling heat exchangers are cooled by the component cooling (CC) system. The containment air recirculation and cooling system removes heat by circulating the post-accident containment atmosphere over coils cooled by the service water (SRW) system. The emergency diesel generator (EDG) jacket water and lube oil coolers are also cooled by SRW. The saltwater system provides the cooling medium for CC and

SRW heat exchangers. The station blackout (SBO) diesel generator is cooled by a fan and radiator arrangement, and the jacket water cooling pump circulates engine coolant through the radiator tubes where engine heat is transferred to the outside air.

To ensure compatibility with commitments made in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment," the inspectors reviewed Constellation's inspection, cleaning, and performance monitoring methods and frequency. The inspectors compared surveillance test and inspection data to the established acceptance criteria to verify that the results were acceptable and that operation was consistent with design.

Chemistry addition processes were reviewed for their effectiveness to ensure heat removal capabilities. The inspectors conducted interviews with knowledgeable personnel to assess challenges with various bio-fouling mechanisms. In addition, the inspectors walked down the SBO and Emergency Diesel Generator (1A and 2B) Rooms, the Unit 1 and Unit 2 CC heat exchangers, and the Unit 2 SRW heat exchangers to assess the material condition of these systems and components. The inspectors also observed maintenance and cleaning of the Unit 2 CC heat exchanger.

The inspectors also reviewed a sample of Issue Reports (IRs) related to the selected heat exchangers. This review was done to ensure that Constellation was appropriately identifying, characterizing, and correcting problems related to these components.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11Q - 1 sample)

a. Inspection Scope

The inspectors observed a licensed operator simulator training scenario conducted on March 9, 2004, in order to assess operator performance as well as operator requalification training. The scenario involved failures and operator challenges that operators encountered during the January 23, 2004 reactor trip event. These included: the tripping of the 22 steam generator feed pump and its failure to reset which resulted in a reactor trip; an excessive steam demand event due to a failure of the turbine bypass valve/atmospheric dump valve quick open circuit; a pressurizer transient which required thermodynamic understanding and evaluation; and the failure of the safety injection actuation signal "B" train to reset. The inspection focused on high-risk operator actions performed during implementation of the emergency operating procedures, emergency plan implementation and classification, and the incorporation of lessons learned specific to the January 23, 2004, reactor trip event. The inspectors also evaluated the clarity and formality of communications, the implementation of appropriate actions in response to alarms, the performance of timely control board operation and manipulation, and the oversight and direction provided by the shift supervisor. The inspectors also reviewed simulator fidelity to evaluate the degree of similarity to the actual control room, especially regarding recent control board modifications.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q - 5 samples)

a. Inspection Scope

The inspectors reviewed the licensee’s effectiveness in performing routine maintenance activities. This review included an assessment of the licensee’s practices pertaining to the identification, scoping, and handling of degraded equipment conditions, as well as common cause failure evaluations and the resolution of historical equipment problems. For those systems, structures, and components scoped in the maintenance rule per 10 CFR 50.65, the inspectors verified that reliability and unavailability were properly monitored and that 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. Documents applicable to this inspection are listed in the Attachment. The inspectors conducted this inspection for the following equipment issues:

- 2A EDG #10 Upper Crankcase Degraded Bearing
- 23 Charging Pump and Gearbox Overhaul
- Unit 2 Train B SIAS Failure To Reset
- 2B EDG Failed ERA Relay
- 12 Charging Pump Motor Replacement

b. Findings

Introduction: A Green non-cited violation was identified for the licensee’s failure to comply with 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, specifically related to the licensee’s failure to perform an adequate root cause evaluation and effectively implement corrective actions associated with the degraded 2A EDG #10 upper crankcase bearing which was identified in 1995. As a result, this condition recurred in October 2003 during which the licensee requested a Notice of Enforcement Discretion (NOED) to support repair activities. During the repair, the licensee identified a distorted journal cap which not only caused the degraded bearing condition in October 2003, but was also the root cause of the degraded condition identified in 1995. The licensee failed to identify the distorted journal cap in 1995, when the opportunity existed, and improperly reinstalled the deformed part.

Description: In March of 1994, the licensee performed a power uprate project on all three Fairbanks-Morse EDGs which increased the rated output from 2500 kW to 3000 kW. This project required a complete overhaul of the engine including the removal and reinstallation of the upper main crankshaft and the associated bearings and bearing journal caps. During the installation of the #10 upper main bearing and its associated bearing cap, the bearing cap was torqued down while improperly aligned. This was recognized because the bearing cap alignment dowel did not fit into the corresponding dowel hole in the upper bearing. Although this was corrected, and the installation was completed, the bearing cap was unknowingly distorted at that time.

On August 23, 1995, during a routine inspection of the 2A EDG, the licensee determined that the #10 upper crankcase bearing did not pass a standard feeler gage dimensional check and upon further inspection determined that the #10 upper bearing was degraded. The licensee conducted discussions with Fairbanks Morse technical representatives pertaining to the aspects of this degraded condition. As a result, the #10 upper bearing was replaced. Measurements were taken during this replacement activity; however, no deficiencies were identified associated with the journal cap. The inspectors reviewed the licensee's root cause that was performed at the time of this repair activity and determined that the root cause lacked sufficient rigor in that it failed to identify the root cause although the opportunity existed at that time. Following the maintenance activities, the 2A EDG was determined to be operable and returned to service.

On October 8, 2003, during the performance of a routine strainer inspection on the 2A EDG, aluminum particles were found in the suction strainer to the standby lube oil pump. The licensee discussed this condition with Fairbanks Morse representatives and determined that the aluminum particles were bearing material since the bearings were the only source of aluminum in the engine. The licensee performed visual inspections on the EDG and determined that the #10 upper crankcase bearing was again degraded, and required replacement. The licensee commenced a more extensive root cause evaluation to address this repetitive, degraded condition. During this evaluation, the licensee performed an additional dimensional check called a mandrel check that was not performed in 1995. This check identified that the #10 upper crankcase bearing journal cap was distorted. The inspectors reviewed the vendor technical manual in order to understand the troubleshooting guidance that was available in 1995, as well as in 2003, and also conducted discussions with engineering personnel to understand the licensee's root cause determinations. Through this review, the inspectors noted that the mandrel check was identified in the appropriate section for troubleshooting bearing issues, and was incorporated in a 1984 vendor technical manual revision although the licensee utilized a 1970 revision during the 1995 troubleshooting and repair activities. The inspectors concluded that had the most current troubleshooting guidelines been utilized during the 1995 occurrence, the distorted journal cap could have reasonably been identified, and not reinstalled. In addition, during the review of the failure analysis report performed by Fairbanks Morse for the 1995 event, which was issued in 1998, the inspectors noted that the report indicated that the failure mechanism was due to improper installation of the bearing and journal cap in 1994. This conclusion was based on identified marks on the upper bearing half that were caused by the alignment dowel on the journal cap during installation. These marks were present during the 1995 repair activity yet did not lead the licensee to the identification of the distorted journal cap which existed at that time. Based on the above, the inspectors determined that the licensee failed to identify the distorted bearing cap in 1995 because the root cause which was performed at that time was inadequate.

Analysis: The performance deficiency associated with this finding was that an adequate root cause evaluation, specific to the degraded bearing condition which existed in 1995, was not performed, and as such, the corrective actions were therefore not adequate to prevent recurrence as evidenced by the same degraded condition recurring in October 2003. Absent the performance of a comprehensive root cause evaluation including critical measurements of the journal cap in 1995, the inspectors concluded that the root cause of this recurring condition could have been determined in 1995, therefore preventing the degraded condition which recurred in 2003. This finding is greater than minor because it affects the Reactor Safety, Mitigating Systems attribute of equipment performance, and the availability, reliability, and capability objective of the mitigating systems cornerstone. If left uncorrected, the condition could have led to the failure of the 2A EDG. This issue was of very low safety significance (Green) because an actual EDG failure did not occur and no safety function was lost. Therefore, this issue screened out of the Phase 1 Reactor Safety SDP as a green finding.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, states, in part that measures shall be established to assure that significant conditions adverse to quality are promptly identified and corrected, and that the cause of the condition is determined and corrective actions are taken to preclude repetition. Contrary to the above, a significant condition adverse to quality involving the 2A EDG existed, and the licensee failed to identify the degraded condition and establish effective corrective actions to preclude repetition. Because this finding is of very low safety significance and has been entered into the licensee’s corrective action program as IR IR2003000375, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC enforcement policy. EA-04-084; NCV 050000318/2004-04-01, Failure To Prevent Recurrence Of A Degraded Bearing Condition.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13 - 5 samples)

a. Inspection Scope

The inspectors reviewed the licensee's assessments concerning the risk impact of removing from service those components associated with the work items listed below. This review primarily focused on activities determined to be risk significant within the maintenance rule. The inspectors compared the risk assessments and risk management actions performed by station procedure NO-1-117, "Integrated Risk Management," to the requirements of 10 CFR 50.65(a)(4), the recommendations of NUMARC 93-01, Revision 2, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Section 11, "Evaluation of Systems to Be Removed From Service," and approved station procedures. The inspectors compared the assessed risk configurations to actual plant conditions to evaluate whether the assessments were accurate and comprehensive. In addition, the inspectors assessed the adequacy of the licensee's identification and resolution of problems associated with maintenance risk assessments and emergent work activities. The inspectors reviewed the following selected work activities:

- 21 CCW Low Flow Switch Failure To Reset
- 23 Charging Pump Overhaul
- 2B EDG Relay Failure
- AFAS Channel "ZF" 21 S/G Hi/Low Level Alarm Relay Failure
- 13 PZR Heater Backup Breaker Failure of 480V Breaker to Close

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

1. Unit 2 Reactor Trip (1 sample)

On January 23, 2004, an automatic reactor trip occurred on Unit 2 from 100 percent reactor power. The inspectors responded to the control room to assess plant response and conditions specific to the event, and to evaluate the performance of licensed operators. The reactor trip was caused by the inadvertent tripping of the 22 steam generator feedwater pump which resulted in lowering steam generator levels resulting in an automatic reactor trip. The event was complicated by multiple equipment deficiencies and operator challenges which ultimately resulted in two safety injection actuations and the loss of the condenser as a secondary heat sink. The inspectors observed control room activities and the licensee's use of emergency procedures while mitigating the event. The inspectors also reviewed control room recorder traces, databases containing information prior to and following the reactor trip, and graphs of critical primary and secondary parameters.

Based on the complicated nature of this trip, which involved multiple equipment malfunctions and potential operator performance deficiencies, the NRC established a Special Inspection Team (SIT) to perform detailed inspection of this event, and address potential deficiencies associated with the event. This inspection was initiated in accordance with NRC Inspection Procedure 71153 “Event Follow-up,” and NRC Management Directive 8.3, “NRC Incident Investigation Program.” The inspection will be conducted in accordance with NRC Inspection Procedure 93812, “Special Inspection,” and documented in NRC Inspection Report 2004-008.

2. Unit 1 Reactor Trip (1 sample)

On March 20, 2004, an automatic reactor trip occurred on Unit 1 from 100 percent reactor power. The inspectors responded to the control room in order to assess the event. The trip was uncomplicated with the exception that the Turbine Bypass Valves (TBV) did not function properly in auto or manual after the quick-open signal cleared. While maintenance technicians were installing a 500 kv bus voltage recorder in control room panel 1C29 as part of preplanned maintenance, a wire was crimped between the recorder and the support railing. This induced a ground fault on non-vital instrument bus 1Y09. This condition lasted for several minutes and caused erratic and failed indications and controls associated with the digital feedwater system. The No. 11 steam generator feedwater pump (SGFP) feedwater regulating valve closed as a result of these control abnormalities, causing both SGFPs to trip on high discharge pressure. The reactor automatically tripped on low SG level in the No. 11 steam generator (SG). Other than the TBV problems, no significant malfunctions in plant equipment occurred that challenged the plant or control room operators. The licensee evaluated the extent of condition associated with the loads on 1Y09 to determine if additional degraded or failed components exist. The results of that inspection revealed no additional degraded components. The inspectors observed control room activities and procedures, and reviewed operator logs to determine if operators performed the appropriate actions in accordance with their training and established station procedures. The unit was restored to 100 percent reactor power on March 22, 2004. Further inspection regarding this event will be documented in NRC Special Inspection Report 2004-008.

3. Unit 1 Rapid Downpower Due To An Actuation Of The Fire Protection System (1 sample)

On March 30, 2004, a rapid downpower was performed on Unit 1 from 100 to 68 percent reactor power. This reduction in reactor power was performed in response to an unanticipated actuation of the fire protection system on the 27 foot elevation in the turbine building. This actuation occurred when ventilation was secured in an asbestos removal enclosure tent and temperatures exceeded the actuation point of a sprinkler head located within the enclosure. In order to preclude the possibility of a reactor trip due to the loss of a steam generator feed pump, the operators made a conservative decision to reduce power to a level that could withstand this loss without the initiation of a reactor trip. The inspectors were notified of this occurrence and responded to the site to assess plant conditions as well as to observe operator performance. The inspectors performed field walkdowns to evaluate the impact that the spray had on plant equipment located on the 27 foot and 12 foot turbine building elevations located underneath the enclosure area. The inspectors noted that some cable trays contained a small amount of water, however, this water was subsequently removed during the licensee's cleanup efforts. The licensee took ground and voltage measurements that were satisfactory, inspected local motor control centers and breakers, and ensured that potentially affected equipment was working properly. In addition, the licensee confirmed that all equipment worked properly during the reduction in power. The inspectors confirmed by reviewing graphs, data, and documents that the licensee maintained reactor parameters within safe limits during the reduction in power. The unit was returned to 100 percent reactor power on March 31, 2004.

1R15 Operability Evaluations (71111.15 - 5 samples)

a. Inspection Scope

The inspectors reviewed operability determinations to verify that the operability of systems important to safety was properly established, that the affected components or systems remained capable of performing their intended safety function, and that no unrecognized increase in plant or public risk occurred. In addition, the inspectors reviewed the selected operability determinations to verify they were performed in accordance with NO-1-106, "Functional Evaluation - Operability Determination," and QL-2-100, "Issue Reporting and Assessment." The inspectors reviewed the operability evaluations for the issues listed below which represented five inspection samples:

- 12 MSIV Excessive Oil Pressure
- 480 Volt Safety-Related Breakers Failures
- Emergency Diesel Generators With Failed ERA Relay
- Unit 1 CVCS Letdown Heat Exchanger Boric Acid Leak
- Unit 1 CVCS Unanalyzed Letdown Piping Support

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19 - 6 samples)

a. Inspection Scope

The inspectors observed and/or reviewed post-maintenance tests associated with the following work activities to verify that equipment was properly returned to service and that proper testing was specified and conducted to ensure that the equipment could perform its intended safety function, as described in the Updated Final Safety Analysis Report, following maintenance.

- 2A Emergency Diesel Generator Pressure Switch Replacement
- 2B Emergency Diesel Generator ERA Relay Replacement
- 1-CVC-504, RWT Charging Pump Suction Valve, Cleanup and Packing Check

- Unit 2 AFAS Channel “ZF” Power Supply Replacement
- Unit 1 ESFAS “B” LOCI Sequencer Replacement
- 1B Emergency Diesel Generator LOCI Sequencer Replacement

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22 - 5 samples)

a. Inspection Scope

The inspectors observed and/or reviewed the five surveillance tests listed below associated with selected risk-significant systems, structures, and components (SSCs) to verify that technical specifications were properly complied with, and that test acceptance criteria were properly specified. The inspectors also verified that proper test conditions were established as specified in the procedures, that no equipment preconditioning activities occurred, and that acceptance criteria had been met.

- STP O-8B-1, Test Of 1B DG And 14 4KV Bus LOCI Sequencer
- STP O-5A-2, Auxiliary Feedwater System Quarterly Surveillance Test
- STP O-8B-2, Test Of 2B DG And 4 KV Bus 24 LOCI Sequencer
- STP O-73F-2, Boric Acid Pump Performance Test
- STP O-73D-1, Charging Pump Performance Test

b. Findings

No findings of significance were identified

1R23 Temporary Plant Modifications (71111.23 - 5 samples)

a. Inspection Scope

The inspectors reviewed temporary modifications to determine whether system operability and availability were affected during and after the completion of the modifications. The inspectors verified that proper configuration control was maintained, appropriate operator briefings were planned, design modification packages were technically adequate, and post-installation testing was performed satisfactorily. The following inspection activities were reviewed against criteria in MD-1-100, Temporary Alterations.

- TMOD # 1-04-004 - Disable Trip Inputs From Digital Speed Monitor (DSM) on the Local Electronic Cabinets 1C194 (11 SGFPT)
- TMOD # 1-04-004 - Disable Trip Inputs From Digital Speed Monitor (DSM) on the Local Electronic Cabinets 1C195 (12 SGFPT)
- TMOD# 2-04-0004 - Remove Overspeed Trip Relay 2FTC21/OST from the SGFP 21 Speed Control

- TMOD# 2-04-0004 - Remove Overspeed Trip Relay 2FTC22/OST from the SGFP 22 Speed Control
- TMOD# 2-04-0006 - Remove Unit 2 SGFP Thrust Wear Trip Inputs

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness (EP)

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes (71114.04 - 1 sample)

a. Inspection Scope

A regional in-office review was conducted of licensee submitted revisions to the emergency plan, implementing procedures and EAL changes which were received by the NRC during the period of January - March 2004. A thorough review was conducted of aspects of the plan related to the risk significant planning standards (RSPS), such as classifications, notifications and protection action recommendations. A cursory review was conducted for non-RSPS portions. These changes were reviewed against 10 CFR 50.47(b) and the requirements of Appendix E. These changes are subject to future inspections to ensure that the impact of the changes continues to meet NRC regulations. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 04, and the applicable requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors observed a control room simulator training exercise conducted on March 9, 2004, to assess licensed operators' performance in the area of emergency preparedness. This training exercise specifically focused on equipment failures and operator challenges that occurred during the Unit 2 reactor trip event on January 23, 2004, and the required procedural transitions and associated event classification. The observed scenario was performed in conjunction with the licensed operator requalification program. Details pertaining to this inspection are provided in Section 1R11 of this report.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01 - 3 samples)

a. Inspection Scope

The inspector reviewed radiological work activities and practices, and procedural implementation during observations and tours of the facilities, and inspected procedures, records and other program documents to evaluate the effectiveness of Calvert Cliffs access controls to radiologically significant areas. This inspection activity represents the completion of 3 samples relative to this inspection area (i.e., inspection procedure sections 02.03.a and 02.05.a and b) in partial fulfillment of the annual inspection requirements.

Problem Identification and Resolution (02.03.a)

During this week of inspection, the inspector reviewed the licensee's self-assessment activities for any results related to the access control program since the last inspection. The intent of this review was to determine if identified problems were entered into the corrective action program for resolution.

High Risk Significant, High Dose Rate HRA and VHRA Controls (02.05.a and b)

On February 2 through 5, the inspector met at various times with the Health Physics General Supervisor, the Health Physics Operations Supervisor, and the Health Physics Support Supervisor and discussed the controls and procedures for high-dose-rate high radiation areas (HRAs) and for very high radiation areas (VHRAs). The inspector reviewed the subject procedures (as listed in the List of Documents Reviewed section) to verify that the level of worker protection was adequate.

Related Activities

On February 2 and 5, the inspector observed Radiologically-Controlled Area (RCA) entries and exits being made by radiation workers at the primary RCA access control point to verify compliance with requirements for RCA entry and exit, wearing of record dosimetry, and issuance and use of alarming electronic radiation dosimeters. The inspector toured various elevations in the auxiliary building to verify the adequacy of the radiological controls which were being implemented. The inspector reviewed observed work activities for compliance with the special work permit (SWP) requirements. During these observations and tours the inspector reviewed, for regulatory compliance, the posting, labeling, barricading, and level of radiological access control for locked high radiation areas (LHRAs), high radiation areas (HRAs), radiation and contamination areas, and radioactive material areas.

On February 4, the inspector examined the materials processing facility (MPF) and inspected the exteriors of locations used for radioactive material storage outside the protected area, including the independent spent fuel storage installation (ISFSI), the storage building for the old steam generators, and a large fenced storage area (Lake Davies).

On February 5, the inspector observed the morning turnover meetings for the Health Physics (HP) staff and for the HP technicians.

The inspector performed a selective examination of documents (as listed in the List of Documents Reviewed section) to evaluate the adequacy of radiological controls.

The review in this area was against criteria contained in 10 CFR 19.12, 10 CFR 20 (Subparts D, F, G, H, I, and J), Technical Specifications, and procedures.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02 - 2 samples)

a. Inspection Scope

The inspector reviewed the effectiveness of the licensee's program to maintain occupational radiation exposure as low as is reasonably achievable (ALARA). This inspection activity represents the completion of two (2) samples relative to this inspection area (i.e., inspection procedure sections 02.01.a and 02.03.a) in partial fulfillment of the annual inspection requirements.

Inspection Planning (02.01.a)

Prior to and during this inspection, the inspector reviewed pertinent information regarding plant collective exposure history, current exposure trends, and ongoing or planned activities in order to assess current performance and exposure challenges. The inspector determined the plant's three-year rolling average collective exposure through the end of 2002. The inspector also reviewed the site's collective exposure for 2003.

Verification of Dose Estimates and Exposure Tracking Systems (02.03.a)

On February 3, at Warehouse 1, the inspector met with the Health Physics Work Leader (Radiological Engineering). During this meeting, the inspector reviewed the assumptions and basis for the current annual collective exposure estimate including that for the estimate for normal operations and that for the planned Unit 1 refueling outage. The inspector also reviewed the applicable ALARA procedures used to determine the methodology for estimating work activity-specific exposures and the intended dose outcome.

Related Activities

Issues, covered in the above-cited discussions, also included trends in on-line and outage exposures, outage SWPs, exposure tracking systems, the outage estimate breakdown, ALARA reviews, and the activities of the site ALARA committee.

Also, on February 3, at the Office Training Facility (OTF), the inspector met with the Health Physics Support Supervisor and discussed the HP high impact team (HIT) plan for the Unit 1 2004 refuel outage and the HP contingency plans, also for the Unit 1 2004 refuel outage.

On February 4, at Warehouse 1, the inspector observed a meeting of the HP HIT at which the 2004 refueling outage activity schedule for containment (April 9 through April 23, 2004) was reviewed.

The inspector performed a selective examination of documents (as listed in the List of Documents Reviewed section) for regulatory compliance and for adequacy of control of radiation exposure.

The review was against criteria contained in 10 CFR 20.1101 (Radiation protection programs), 10 CFR 20.1701 (Use of process or other engineering controls), and procedures.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03 - 1 sample)

a. Inspection Scope

The inspector reviewed the program for health physics instrumentation to determine the accuracy and operability of the instrumentation. This inspection activity represents the completion of one (1) sample relative to this inspection area (i.e., inspection procedure section 02.04.b) in partial fulfillment of the annual inspection requirements.

Problem Identification and Resolution (02.04.b)

During this inspection, the inspector reviewed corrective action program reports related to incidents involving radiation monitoring instrument deficiencies since the last inspection in this area. The inspector interviewed the Health Physics Work Leader (Radiation Instruments) and discussed the reported radiation monitoring deficiencies and their resolution. The inspector also toured the radiation instrumentation calibration facilities in the South Service Building (SSB) and in the Office Training Facility (OTF).

The inspector performed a selective examination of documents (as listed in the List of Documents Reviewed section) for regulatory compliance and adequacy in this area.

The review was against criteria contained in 10 CFR 20.1501, 10 CFR 20 Subpart H, Technical Specifications, and procedures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

40A1 Performance Indicator Verification (71151)

During an EP program inspection conducted in July 2002 (50-317/02-010, 50-318/02-010), the inspector identified an Unresolved Item **(URI 50-317/02-010-02, 50-318/02-010-02)** regarding the licensee's Alert and Notification System (ANS) PI data. Specifically, due to operational problems because of an aging ANS, the licensee changed their testing methodology to perform three consecutive tests versus one during their weekly silent tests. They chose three tests because at a minimum, one of the three signals would result in a successful activation. However, when reporting the ANS PI data, the licensee considered the three silent tests as one test but was reporting successes on any of the three tests. The inspector determined that by not counting all the tests, the licensee could be unintentionally masking failures which may provide a false impression that the system was operating at a high performance level.

Constellation Generation Group believed the calculation of the data was correct because their testing method mimicked the signal activation of state-of-the-art systems currently being used by other power plants even though their system didn't operate in that manner. Constellation Generation Group submitted a Frequently Asked Question (FAQ) to the Nuclear Energy Institute (NEI) to determine if their interpretation of the guidance set forth in NEI 99-02, Revision 2 is correct and entered the issue in their corrective action system (No. IR3-021-087).

In November 2002, Constellation Generation Group presented their issue before the Reactor Oversight Process (ROP) Working Group Committee. In June 2003, the ROP Working Group Committee decided the issue would be reviewed generically (FAQ No. 35.7) with respect to whether a licensee is able to modify their ANS testing methodology for calculating the site ANS PI data. In February 2004 the FAQ was finalized which included a response specific to the Calvert Cliff's issue. The FAQ response stated it was not necessary for Constellation Generation Group to re-calculate their past PI data from the time of the change; however, the response directed the licensee to update the ANS PI data report by noting they had changed their testing method in the comment section which was submitted with their first quarter 2004 PI data report. Meanwhile, Constellation Nuclear Generation replaced their aging ANS in late 2003 with a newer system and changed their testing methodology back to counting each push as a test to accommodate the operability of the system. URI 50-317/02-010-02, 50-318/02-010-02 is considered closed.

4OA2 Identification and Resolution of Problems

1. Annual Sample Review

a. Inspection Scope

The inspector selected seven issues identified in the Corrective Action Program (CAP) for detailed review (Issue Report Nos. IR4-008-987 and -988, IR4-009-607, -608, -642, and -680, and IR4-023-854). The issues were associated with site dose reduction, inadvertent release of radioactive material from the RCA, position qualifications, completion and documentation of required training, negative trends in written communications identified by self-assessment review, and documentation of radioactive material storage locations. On February 5, the inspector met with the Health Physics Support Supervisor to discuss these Issue Reports. The documented reports for the issues were reviewed to ensure that the full extent of the issues was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized.

b. Findings

No findings of significance were identified.

2. Annual Sample Review

a. Inspection Scope (1 sample)

The inspector selected Issue Report (IR) IR4-013-246 for detailed review. The IR identified a wall thinning condition downstream of flow orifice 1-FO-3710 in the Unit 1 reheat steam system. The wall thickness remaining was found to be degraded below specification requirements. This piping segment is scheduled for replacement during the refuel outage beginning April 2004, and, is currently restored to full pressure retaining capability by the installation of a mechanical clamp over the degraded area.

The IR was reviewed to ensure a complete and accurate identification of the issue, an appropriate root cause evaluation was performed, extent of condition was considered and corrective actions were specified and verified as completed. The IR and the resolution documents were reviewed against the requirements of Constellation Nuclear's corrective action process. The inspector noted that during the review of extent-of-condition activities, the licensee replaced those piping segments downstream of the flow orifice on the remaining three moisture separator reheaters for Units 1 and 2.

The inspector noted that additional issue reports and a self assessment had been recently initiated related to the implementation of the Flow Accelerated Corrosion (FAC) Program. Consequently, the inspector selected IR4-028-240, IR3-058-986, IR4-013-245, IR4-013-246 and Self Assessment 200200117 for review to assess the effectiveness of the FAC Program in meeting the requirements of NRC Bulletin 87-01 and Generic Letter 89-08 regarding the implementation of a Program to ensure that erosion/corrosion does not lead to degradation of single phase and two phase high-energy carbon steel systems.

The inspector also conducted interviews with personnel responsible for the implementation of the flow accelerated corrosion program to assess the effectiveness of the program to detect degraded pipe wall thickness in high energy applications.

b. Findings

No findings of significance were identified.

3. Effectiveness Of Corrective Actions Associated With Mispositioning Events

a. Inspection Scope (1 sample)

The inspectors reviewed the licensee's corrective action program documents pertaining to component mispositioning events. Including in these were issue reports, causal analysis reports, and previously implemented corrective actions. The inspectors also conducted interviews with various station personnel.

b. Findings

Introduction: The inspectors identified a self-revealing finding of very low safety significance (Green) which resulted in a non-cited violation (NCV) for the licensee's failure to establish adequate corrective actions associated with component mispositioning events as required by 10 CFR Part 50 Appendix B, Criterion XVI, "Corrective Actions."

Description: During the period of time between January 7, 2002 and March 31, 2004, there have been a total of fifty two component mispositioning events which were identified by the licensee and entered into their corrective action program. An NRC problem identification and resolution (PI&R) team inspection, which concluded on November 7, 2003, assessed 45 of these events which occurred between January 7, 2002, and October 28, 2003. This assessment resulted in the identification of a Green finding associated with the licensee's failure to adequately establish and implement corrective actions to address the negative trend associated with component mispositionings [Inspection Report IR-2003-009, NCV 05000317; 05000318/2003009-01].

On October 29, 2003, the licensee issued IR4-016-119 to address this negative trend. As a result, the licensee developed root causal analysis, IR200300402, which identified several underlying causes of the component mispositioning events. This analysis, dated December 23, 2003, provided a number of corrective actions designed to prevent the recurrence of mispositioning events.

Subsequent to these actions, the inspectors reviewed component mispositioning events that occurred between October 29, 2003, and March 31, 2004. These events represented seven of the fifty two events. Four of these events were classified as Category II IRs, which warranted a causal analysis; however, the inspectors determined that only two of these had risk significance. The first event occurred on March 4, 2004, during the performance of STP M-213-1, Calibration of Power Range Instrumentation by Comparison with Incore Nuclear Instrumentation. This STP was being performed on channel 'D' of the Unit 1 Reactor Protection System. During the performance of this test, an instrumentation and controls technician inadvertently placed the channel 'C' operate/test switch to "zero." This resulted in a unintended trip condition on channel 'C', placing the system in a condition where a single failure in either the 'A' or 'B' channels could have resulted in a unit trip. The second event occurred on March 21, 2004, during the performance of OI-2A, "Chemical & Volume Control System," Section 6.10, "Purge and Establishment of Hydrogen Overpressure," when operators inadvertently closed valve 1-CVC-501, VCT Outlet Isolation. Although this valve was in a closed position for less than a minute, this action resulted in a loss of suction to all three charging pumps, causing the 12 charging pump to trip on low suction head, and causing the 13 charging pump to become gas bound. The 11 charging pump was not running at this time and was immediately available once suction was reestablished to the volume control tank (VCT). In light of these events, the inspectors determined that the licensee's corrective actions to address component mispositioning thus far have not been fully effective in preventing component mispositioning events associated with risk significant components.

During the inspectors' review of component mispositioning events, the inspectors noted an increase in tagout errors. Specifically, between October 29, 2003, and March 31, 2004, there were four tagout errors. Two of these were associated with safety-related systems, however, the inspectors determined that only one of these errors could have been potentially risk significant. This error involved a clearance order that intended to isolate the 22 service water (SRW) system by closing 2-SW-386, Manual SW Outlet. The tagout incorrectly directed the closure of 2-SW-253, 21 A/B SRW Heat Exchanger Salt Water Outlet Isolation Valve. Had the tagout been performed as written, saltwater flow to both SRW subsystems would have been isolated, causing both subsystems to become inoperable. As field operators started closing 2-SW-253, "21 Saltwater Flow Trouble" alarm was received in the control room. At the same time, field operators recognized changes in flow noises and stopped the tagout evolution, recognizing that the tagout was in error. The inspectors determined that this tagout error did not result in any adverse consequences to the plant, but considered the recent increase in tagout errors to be a contributor to the already identified negative trend of component mispositionings.

Analysis: The inspectors determined that the ongoing adverse trend specifically associated with the safety-related component mispositioning events mentioned above constituted a significant condition adverse to quality, and that the licensee's failure to take appropriate and timely corrective actions to resolve this negative trend constituted a performance deficiency. This finding is greater than minor because it affected the human performance attribute and the availability, reliability, and capability objectives of the mitigating system cornerstone.

The significance of this finding was evaluated in accordance with NRC Manual Chapter 0609, Appendix A, Attachment 1, "Significance Determination Process (SDP) for Reactor Inspection Findings for At-Power Situations," and was determined to be of very low safety significance (Green) since none of the events resulted in the actual loss of a system safety function therefore, this issue screened out of the Phase I SDP as a Green finding.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected; and for significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude recurrence. Contrary to the above, two significant conditions adverse to quality involving component mispositioning events associated with safety-related systems occurred between October 29, 2003, and March 31, 2004. These events are a continuance of a previously identified negative trend. The inspectors concluded that in light of the previously identified non-cited violation associated with component mispositioning events, prompt and effective corrective actions have not been adequately established to prevent the recurrence of similar events. Because these mispositioning events were of very low safety significance, and have been entered into the licensee's corrective action program as IR4-030-128 and IR4-031-134 respectively, this violation is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. NCV 05000317; 05000318/2004-004-02, Failure To Implement Effective Corrective Actions Associated With Component Mispositioning Events.

3. Cross-References to PI&R Findings Documented Elsewhere

Section 1R12 describes a finding for failure to identify a degraded condition regarding a distorted journal cap on the 2A EDG. The licensee had an opportunity to identify the degraded condition in 1995.

4OA3 Event Follow-up (7 samples)

1. <u>(Closed) Licensee Event Report (LER) 50-318/2003-01</u>, Emergency Air Lock Containment Penetration Closure Requirements Violation

   On February 24, 2003, plant personnel identified a condition prohibited by technical specifications where a temporary hose penetrating the containment emergency air lock temporary closure device was not sealed, and core alterations had been ongoing. Specifically, on February 23, core alterations (control element assembly uncoupling) were performed for approximately 8 hours and the containment emergency air lock temporary closure device was not closed (sealed) for approximately 5 of the 8 applicable hours, as required by technical specifications. The licensee determined the cause to be human error in that work packages were inadequate and there were inadequate communications. The work packages did not provide caution statements or adequately describe containment closure requirements necessary when performing work activities at the emergency air lock temporary closure device penetrations. The site procedure containing these cautions and closure requirements was not included in the work packages. Communications were inadequate in that the requirements for containment closure were not communicated or known to the individuals performing the task. Corrective actions included changing plant procedures to require installation of chains and signs at the emergency air lock requiring notification of operations prior to entry and to require planners to include containment closure compliance steps in future work packages. This finding is more than minor because the finding is associated with the Barrier Integrity Cornerstone configuration control attribute and affected the cornerstone objective. The finding was considered to have very low safety significance (Green) using Appendix H of the SDP because the event did not occur within 8 days of the start of the outage. The inspector reviewed the procedure changes, and discussed the event and procedure changes with site personnel. This licensee-identified finding involved a violation of technical specifications and enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

2. <u>(Closed) Licensee Event Report (LER) 50-318/2003-02</u>, Unintentional Reactor Protective System (RPS) Actuation During Plant Heatup

   On April 19, 2003, during startup surveillance testing, while all control element assemblies were fully inserted into the core, Unit 2 received an automatic trip signal due to steam generator low pressure automatic bypass resetting prior to the trip signal reset. Calvert Cliffs personnel determined that the cause for the event was a combination of setpoint tolerance, system design, and operating conditions. Corrective actions taken included revising related procedures to establish initial conditions such that tests cannot be conducted in the steam generator pressure range where this RPS actuation could occur, and evaluating all other RPS and Engineered Safety Features Actuation System trip inputs for similar unanticipated actuations resulting from configurations currently allowed by procedure. The inspector reviewed the procedure changes, and discussed the event and procedure changes with site personnel. The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented the event in Issue Report IR4-018-667. This LER is closed.

3. <u>(Closed) Licensee Event Report (LER) 50-318/2003-04-00 & 50-318/2003-04-01</u>, Technical Specification Exceeded Due to Extended Repair of Diesel Generator

On October 10, 2003, the licensee requested a Notice of Enforcement Discretion (NOED) due to the extended repair of the 2A EDG. The licensee determined the root cause of this event to be a human performance deficiency associated with the failure to identify a distorted journal cap in 1995 following an installation error of the journal cap and upper bearing in 1994. Details of this event are provided in Section 1R12 of this report. These LERs are closed.

4. <u>(Closed) Unresolved Item (URI) 50-318/2003-06-02</u>, Review of Previous Maintenance and Vendor Related Activities Associated with the 2A EDG

On October 10, 2003, the NRC granted a Unit 2 NOED related to enforcing compliance with the requirements of Technical Specification(TS) 3.8.1, AC Sources - Operating. This was based on the licensee's inability to perform repair activities on the 2A EDG #10 upper crankcase bearing within the established allowable outage time. The inspectors reviewed the applicable TS requirements, assessed the licensee's inspection efforts pertaining to potential common-mode failure mechanisms affecting the other EDGs, and monitored compliance for granting of the NOED as well as the implemented compensatory actions during the extended outage duration.

Details pertaining to the dispositioning of this item are contained in Section 1R12 of this report. This URI is closed.

5. <u>Unit 2 Reactor Trip</u>

a. <u>Inspection Scope</u>

On January 23, 2004, the inspectors responded to the control room to assess plant conditions and operator performance following a Unit 2 reactor trip from 100 percent reactor power. This reactor trip was caused by the inadvertent tripping of the 22 steam generator feed pump which resulted in the lowering of steam generator levels below automatic reactor trip setpoints.

Based on the complicated nature of this trip, which involved multiple equipment malfunctions and operator performance deficiencies, the NRC established a Special Inspection Team (SIT) to perform detailed inspection of this event, and address potential deficiencies associated with the event. This inspection was initiated in accordance with NRC Inspection Procedure 71153 "Event Follow-up," and NRC Management Directive 8.3, "NRC Incident Investigation Program." The inspection will be conducted in accordance with NRC Inspection Procedure 93812, "Special Inspection," and documented in NRC Inspection Report 2004-008.

b. <u>Findings</u>

No findings of significance were identified.

6. Unit 1 Reactor Trip

a. Inspection Scope

On March 20, 2004, the inspectors responded to the control room to assess maintenance activities that were in progress prior to a Unit 1 reactor trip, as well as plant conditions and operator performance following the event. The reactor trip occurred while at 100 percent reactor power. The trip was caused when maintenance activities induced a ground fault which resulted in erratic indications and failures associated with the digital feedwater system.

Based on the time that this event occurred, and in light of the ongoing NRC special inspection associated with the Unit 2 reactor trip mentioned above, the NRC determined to amend the original special inspection charter for the Unit 2 trip event, in order to appropriately assess related factors associated with this trip. Inspection results pertaining to this event will be documented in NRC Inspection Report 2004-008.

b. Findings

No findings of significance were identified.

7. Rapid Downpower Due To Fire Protection System Actuation

a. Inspection Scope

On March 30, 2004, the inspectors responded to the site to evaluate conditions leading up to and following a rapid downpower on Unit 1 from 100 percent to 68 percent reactor power. This downpower was performed as a conservative, anticipatory measure to preclude a potential reactor trip associated with the loss of a steam generator feedwater pump following the actuation of the fire protection system. A sprinkler head contained within an asbestos removal enclosure tent activated after exceeding its temperature setpoint and sprayed down cable trays in the vicinity of digital feedwater system control panels.

The inspectors reviewed station procedures to ensure compliance, performed walkdowns of the affected areas, and conducted discussions with engineering personnel to understand the circumstances that led to the actuation as well as the extent of condition prior to commencing a power increase. Further details pertaining to this event are provided in Section 1R14.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

Spent Fuel Material Control and Accounting at Nuclear Power Plants - Temporary Instruction 2515/154

Temporary Instruction 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants, Phase I and Phase II, were completed during this inspection period. Appropriate documentation was provided to NRC management as required.

4OA6 Meetings, including Exit

On April 8, 2004, the inspectors presented the inspection results to Kevin Neitmann and other members of his staff. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

Technical Specification 3.9.3, Containment Penetrations, requires during core alterations, that the emergency air lock temporary closure device be closed. Contrary to this, on February 23, 2003, the closure device was not closed in that a hose penetrating the closure device was not sealed. This was identified in the corrective action program as IR4-015-307. This finding is of very low safety significance because it did not occur within 8 days of the start of the outage.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Ball, Health Physics Work Leader, Radiological Engineering
S. Brown, Health Physics Work Leader, Operations
Bill Carey, Operator
Keith Crissman, Electrical Maintenance
Sonny Dean, Auxiliary Systems Manager
Paul Fatka, System Manager
Dave Frye, Shift Manager
P. Furio, Supervisor, Regulatory Matters
M. Geckle, Operations Manager
J. Gines, Mechanical Engineering Consultant
Chip Grooms, Shift Manager
J. Guidotti, Health Physics Work Leader, Radiation Instruments
Calvin Hancock, Health Physics Supervisor
D. Holm, Manager, Nuclear Maintenance
Mark Hunter, System Manager
S. Hutson, Outage Management
J. Johnson, Health Physics Technician
Al Kelly, Senior Reactor Operator
Keith King, Senior Reactor Operator
T. Kirkham, Radiation Protection Supervisor
Joe Klecha, Operator
Ed Kreahling, System Manager
Hien Le, System Manager
J. Lenhart, Health Physics Work Leader, Operations
Randy Lewis, Operator
S. Loeper, mechanical Engineering Consultant
Dave Lynch, Shift Manager
Dale McElheny, System Manager
Roger McPherson, Operator
Homero Montes De Oca, Electrical Maintenance Supervisor
K. Neitmann, Plant General Manager
Bob Pace, Shift Manager
B. Pickett, Health Physics Technician
Tom Pilkerton, Mechanical Maintenance Supervisor
Mike Polak, Secondary Systems Manager
I. Rice, Health Physics Technician
S. Sanders, General Supervisor, Radiation Safety
Curtis Scayles, Mechanical Maintenance Supervisor
A. Simpson, Regulatory Matters Supervisor
B. Scott, Mechanical Engineering Consultant

G. Vanderheyden, Vice President
Larry Vandersnick, Operator
Larry Williams, Systems Manager
J. York, Health Physics Support Supervisor
M. Yox, Engineering Analyst

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

None

Opened and Closed

050000318/2004-04-01, EA-04-084	NCV	Failure To Prevent Recurrence Of A Degraded Bearing Condition (Section 1R12)
05000317; 05000318/2004-04-02	NCV	Failure To Implement Effective Corrective Actions Associated With Component Mispositioning Events (Section 4OA2)
50-318/2003-01	LER	Emergency Air Lock Containment Penetration Closure Requirements Violation (Section 4OA3)
50-318/2003-02	LER	Unintentional Reactor Protective System (RPS) Actuation During Plant Heatup (Section 4OA3)
50-318/2003-04-00, 01	LER	Technical Specification Exceeded Due to Extended Repair of Diesel Generator (Section 4OA3)

Closed

50-317; 318/02-010-02	URI	ANS PI Data potentially not being calculated properly. (Section 4OA1)
50-318/2003-06-02	URI	Review of Previous Maintenance and Vendor Related Activities Associated with the 2A EDG (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Partial System Walkdowns:

12 Charging Pump Motor Replacement

IR4-030-135, Amptector settings were not for new motor
STP O-073D-1, Charging Pump Surveillance
MO 10410039: “Replace 12 Chg PP Motor”
MO 1200103863: “Replace 12 Chg PP Motor”
MO 1200304005: “Inspect & Lube 12 Chg PP”

23 Charging Pump Packing Replacement And Gearbox Replacement

IR3-031-677: "Requests the Use of 'Belzona' on Charging Pumps to Prevent Leakage
IR3-081-605: "Overhaul 23 Charging Pump Gear Reducer
STP-O-73D-2, Charging Pump Performance Test
MO2200304052, Install New 23 Charging Pump Motor
MO 2200303145, Calibrate 23 Charging Pump Controls and Alarms
MO 2200102394: "Overhaul 23 Charging Pump Gear Reducer"
MO 2200303331: "Lube/Inspect 23 Charging Pump Coupling"
MO 2199903414: "Application of 'Belzona' to Reduce Leakage at Suction and Discharge Valves"
MO 2200300280: "Radiological Testing of 2CKVCVC-177 23 Charging Pump Discharge Valve"
Technical Procedure CVCS-08: "Charging Pump Valve Replacement"
Technical Procedure CVCS-11C, Charging Pump Packing Removal and Replacement of Garlock V-Ring Packing
Technical Procedure CVCS-12: Charging Pump Stuffing Box Replacement
Technical Procedure CVCS-04: "Charging Pump Gear Reducer Overhaul"

2CVC-348 Valve Replacement

Safety Tagging Clearance is 2200400025
Drawing 62730SH0001 Chemical and Volume Control System
Letter from J.W. Singleton to Shift Manager dated February 4, 2004 Subj.: Reactivity Guidance for Unit 2 Maintenance.

Section 1R05: Fire Protection

Issue Reports:

IR4-029-083, A small smoldering fire was called away outside the weld shop by large trash dumpster

Manual:

Fire Fighting Strategies Manual

Section 1R07: Heat Sink Performance

Calculations and Drawings

Calculation 4710 Rev 1-PHEETP & PHETREND. DOC SRW HX Test Evaluation
Drawing No. 62708SH0003, Rev.7, Circulating Saltwater System Diagram
Drawing No. 60708SH0003, Rev.16, Circulating Saltwater Cooling System Diagram
Drawing No. 60708SH0002, Rev.101, Circulating Saltwater Cooling System Diagram
Drawing No. 62708SH0002, Rev.95, Circulating Saltwater Cooling System Diagram
Drawing No. 60706SH0001, Rev.48, Service Water Cooling Turbine Area Diagram
Drawing No. 60706SH0002, Rev.73, Service Water Cooling Auxiliary Building and Containment Diagram
Drawing No. 62706SH0002, Rev.64, Service Water Cooling Auxiliary Building and Containment Diagram

Design Specifications

Design specifications, ESP No: ES199501141, Service Water Plate Heat Exchangers

Issue Reports

IR4-026-331	IR3-062-023	IR3-078-954
IR4-026-354	IR3-063-326	IR3-062-368
IR4-011-418	IR3-062-136	IR4-006-528
IR4-009-357	IR3-063-110	IR4-005-286
IR4-015-890	IR3-076-358	IR4-016-650
IR4-004-010	IR3-070-122	IR4-023-801
IR4-000-158	IR4-023-493	IR4-017-074

IR Resolution Document

AIT # IR200200364	AIT # IR200200415	AIT # IR200200414
AIT # IR200200543	AIT # IR200200393	AIT # IR200200718
AIT # IR200300191	AIT # IR200200317	AIT # IR200300435
AIT # IR200300054	AIT # IR200300198	AIT # IR200300367

IR Screening Results

IR3-058-793	IR3-076-358	IR3-063-110
IR3-070-122	IR3-062-023	IR3-063-326
IR3-062-368	IR3-078-954	IR4-006-202
IR4-011-418	IR4-009-357	

System Health Reports & Trending Data

Auxiliary systems chemistry evaluation for 4th Quarter of 2002
ES200100668, Engineering evaluation on Service water heat Exchanger

Work Orders and Change Request

MO# 2200200624 - Inspect and Clean #21 Containment Air Cooler Coils
MO# 2200200923 - Inspect #23 Containment Air Cooler
MO# 2200200896 - Inspect #23 Containment Air Cooler Coils

Calvert Cliffs UFSAR

Calvert Cliffs UFSAR - 1.8 Station Blackout
Calvert Cliffs UFSAR - 6.4 Containment Spray System
Calvert Cliffs UFSAR - 6.5 Containment Air Circulation and Cooling System
Calvert Cliffs UFSAR - 8.4 Station Blackout Diesel Generator
Calvert Cliffs UFSAR - 9.5 Cooling Water systems - Component cooling, Service water and Saltwater
Calvert Cliffs UFSAR - 9.8 Plant Ventilating Systems

Miscellaneous

Generic Letter 89-13 Program Description
EPRI NP-7552, Heat Exchanger Performance Monitoring Guidelines
EPRI TR-107397, Service Water Heat Exchanger Test Guidelines
Letter from BGE - Calvert Cliffs Nuclear Power Plant to U.S. Nuclear Commission, Generic Letter 89-13 June 30, 1994, Response

Section 1R11: Licensing Operator Requalification Program

Procedures:

ERPIP 3.0, Immediate Actions

Other:

Simulator Operator Examination For The Licensed Operator Training Program At The Calvert Cliffs Nuclear Power Plant, approved on November 13, 2003.

Section 1R12: Maintenance Effectiveness

2A EDG #10 Upper Crankcase Degraded Bearing

IR4-017-074, The degradation found on the 2A DG #10 upper bearing has raised questions about the continued operability of the other diesel generators. The IR is written to address this concern
Reasonable Expectation of Continued Operability IR4-017-074 Metal particles in the 2A DG Lube oil recirc pump strainer
STP O-8A-2 Test of 2A DG AND 4 KV BUS 21 LOCI SEQUENCER
MO# 1199503076 Inspect & Replace upper main crankshaft & connection rod bearings
MO# 1199405932 Perform Mini inspections of 11 EDG per procedures EDG-112 to comply with NRC commitment. Request tech rep for inspection.
MO# 1199503077 The intent of this MO is to perform ETP #95-061 on #11 EDG after bearing replacement under MO# 1199503076
MO# 19303478 Perform up-grade on #11 EDG IAW #93 - 203M.1-1
Technical Manual 3800TD8-1/8 Corrective Procedures for Main and Rod Bearings
Category I Root Cause Analysis 2A DG #10 Upper Main Bearing

Unit 2 Train B SIAS Failure To Reset

MO 2200400304, Fix SIAS B Loose Wire
IR4-025-652, Actual Failure of SIAS B Reset
IR4-027-008, Identification of PMT Shortcoming
EN-1-101, Design Change and Modification Implementation
OI-34, Revision 19, Engineered Safety Features Actuation System
Drawing 63059A, Electrical Schematic ESFAS
Drawing 87310, SH 0002, Wiring Panel 2C10 ESF Control

2B EDG Failed ERA Relay Replacement

MO 2200401030, Repair failed ERA relay on 2B EDG
IR4-029-432, Failure of ERA Relay following a slow speed start
STP O-8B2, Test of 2B EDG and 4KV bus LOCI Sequencer

12 Charging Pump Motor Replacement

MO 1200103863, Replace 12 charging pump motor
MO 1200304005, Inspect & Lube 12 charging pump
IR4-030-135, Ampdetector settings were not correct for new motor
STP O-073D-1, Charging pump surveillance

23 Charging Pump Packing Replacement And Gearbox Replacement

IR3-031-677, Requests the Use of ’Belzona’ on Charging Pumps to Prevent Leakage
IR3-081-605, Overhaul 23 Charging Pump Gear Reducer
STP-O-73D-2, Charging Pump Performance Test
MO 2200304052, Install New 23 Charging Pump Motor
MO 2200303145, Calibrate 23 Charging Pump Controls and Alarms
MO 2200102394, Overhaul 23 Charging Pump Gear Reducer
MO 2200303331, Lube/Inspect 23 Charging Pump Coupling
MO 2199903414, Application of ’Belzona’ to Reduce Leakage at Suction and Discharge Valves
MO 2200300280, Radiological Testing of 2CKVCVC-177 23 Charging Pump Discharge Valve
Technical Procedure CVCS-08, Charging Pump Valve Replacement
Technical Procedure CVCS-11C, Charging Pump Packing Removal and Replacement of Garlock V-Ring Packing
Technical Procedure CVCS-12, Charging Pump Stuffing Box Replacement
Technical Procedure CVCS-04, Charging Pump Gear Reducer Overhaul

Section 1R13: Maintenance Risk Assessment/Emergent Work Evaluation

AFAS Channel “ZF” 21 S/G Hi/Low Level Alarm Relay Failure

IR4-028-793, AFAS Channel “ZF” on 21 S/G for low and high level tripped
MO# 2200400459, Check and replace power supply
MN-1-101 Rover report for actions associated with MO#2200400459

13 PZR Heater Backup Breaker Failure of 480V Breaker to Close

IR4-029-151, Breaker 52-1427 (111 PH Pressure Heater MCC) would not manually recharge after tripping during performance of STP O-56D-1.
IR4-002-245, 480 V Load Centers; 5 functional failures since OCT2003.
IR4-002-246, 480V Breaker 52-1427 PZR Backup heaters
DWG. 61009 Single Line 480V Unit Buses (Unit 1)
DWG. 63009 Single Line 480V Unit Buses (Unit 2)
DWG. 61072SH00A2, Typical Load Center Breaker with or without overcurrent trip switch operation details
DWG. 61-072-C SH.A1, Typical 480V Load Center Operation Details
CCNPP Procedure FTE-52- Westinghouse DS-416 Circuit Breaker and Cubicle Inspection
MN-1-101 Attachment 2 IR Rover MO documentation and closeout
MO 1200400613 Feeder to MCC 111 PZR heater springs won’t recharge.
MO 1199903249 Inspect MCC-111 Feeder Breaker 52-1427
MO 1200103402 Inspect MCC-111 Feeder Breaker 52-1427
MO 1199704312 Inspect MCC-111 Feeder Breaker 52-1427

23 Charging Pump Packing Replacement And Gearbox Replacement

IR3-031-677, Requests the Use of 'Belzona' on Charging Pumps to Prevent Leakage
IR3-081-605, Overhaul 23 Charging Pump Gear Reducer

STP-O-73D-2, Charging Pump Performance Test
MO 2200304052, Install New 23 Charging Pump Motor
MO 2200303145, Calibrate 23 Charging Pump Controls and Alarms
MO 2200102394, Overhaul 23 Charging Pump Gear Reducer
MO 2200303331, Lube/Inspect 23 Charging Pump Coupling
MO 2199903414, Application of 'Belzona' to Reduce Leakage at Suction and Discharge Valves
MO 2200300280, Radiological Testing of 2CKVCVC-177 23 Charging Pump Discharge Valve

Technical Procedure CVCS-08, Charging Pump Valve Replacement
Technical Procedure CVCS-11C, Charging Pump Packing Removal and Replacement of Garlock V-Ring Packing
Technical Procedure CVCS-12, Charging Pump Stuffing Box Replacement
Technical Procedure CVCS-04, Charging Pump Gear Reducer Overhaul

2B EDG Failed ERA Relay Replacement

MO 2200401030, Repair failed ERA relay on 2B EDG
IR4-029-432, Failure of ERA Relay following a slow speed start
STP O-8B2, Test of 2B EDG and 4KV bus LOCI Sequencer

21 Component Cooling Water Lo Flow Instrument Failure To Reset

IR4-019-566, Significant Increase in RCP Parameters During Ccw Pump Test
STP-0-73C-2, Component Cooling Pump Quarterly Test
Letter Dated March 8, 2004, CCW Transients and RCP Operation

Section 1R15: Operability Evaluations

Unit 1 Letdown Heat Exchanger Boric Acid Leak

IR3-003-918, U-1 Letdown Heat Exchanger end bell gasket is leaking. Boric acid is present
IR4-023-330, Investigation of IR4-003-918 showed that the Unit 1 Letdown Heat Exchanger has two active leaks one at the inlet flange and one at the end bell flange
NO-1-106 Reasonable Assurance of Safety Dated 1/29/04
NO-1-106 Reasonable Assurance of Safety Dated 2/10/04

Unit 1 Letdown Support Seismic Evaluation

IR4-009-406, While performing ISI visual exam of support, examiner found clearances were not as shown on drawing
Visual Examination Report for 24" HC-3-1001 dated 2/2/04
DWG. No. 91097SH0012 (isometric) 24-HC3-1001
NO-1-106 Reasonable Assurance of Safety Dated 2/5/04

12 MSIV Excessive Oil Pressure

IR4-027, 12 MSIV Oil Pressure Exceeding Specifications Of 4000 psi
RECO dated 1/14/04, Excessive Oil Pressure In 12 MSIV
STP O-1-1, MSIV Full Stroke Test

480 Volt Safety-Related Breakers

IR4-028-843, Anti-bounce latch sticking caused breaker failure
IR4-029-151, Grease hardening caused breaker failure
IR4-029-228, CX relay failure causes breaker not to charge the closing springs
IR4-027-382, CX relay failure
IR4-029-228, 11 Stator liquid cooling pump does not start
IR4-028-152, Performance of 1 ohm resistance checks of CX relay contacts
RECO, dated 2/27/04, Operability of Westinghouse DS 480 volt breakers with Westinghouse BDT022S originally installed relays
Technical Procedure FTE-53, Westinghouse DS-206 Circuit Breaker And Cubicle Inspection
Letter, dated August 17, 1972, 480 volt load center breaker time delay circuits
Maintenance Rule Scoping Document, Electrical 480 Volt Transformers and Buses

Emergency Diesel Generators With Failed ERA Relay

IR4-029-432, 2B EDG ERA relay did not pick up following the slow speed start
MO 2200401030
STP O-8B-2, Test Of 2B DG And 4KV Bus 24 LOCI Sequencer

Section 1R19: Post-Maintenance Testing

1-CVC-504-MOV RWT Charging Pump Suction following boric acid buildup removal and packing check

IR4-000-847, Boric Acid Buildup was noted on valve 1-CVC-504-MOV
MO#1200302911, Verify packing torque on 1MOV504
MO#1200302810, 1MOV504 Inspect/Lubricate Operator IAW MOV-12
STP O-65A-1, CVCS Valve Quarterly Operability Test

Unit 2 AFAS Channel “ZF” power supply replacement

IR4-028-793, AFAS channel ZF on 21 SG for low and high level tripped

Unit 1 ESFAS “B” LOCI Sequencer Replacement

STP O-8B-1 Test of 1B DG and 14 4KV Bus LOCI Sequencer
IR4-028-768, During the performance of STP O-8B-1 the sequencer returned to the blocked position and restarted unexpectedly

1B Emergency Diesel Generator startup LOCI Sequencer Replacement

STP O-8B-1 Test of 1B DG and 14 4KV Bus LOCI Sequencer

2A Emergency Diesel Generator Pressure Switch Replacement

IR4-024-923, 2A EDG receiver is sticking, not allowing compressor to stop
MO 2200305611

2B Emergency Diesel Generator ERA Relay Replacement

STP O-8B-2, Test Of 2B DG And 4 KV Bus 24 LOCI Sequencer

Section 2OS1: Access Control To Radiologically Significant Areas

Procedure MN-1-116, Rev. 8, Control of diving activities in radiologically controlled areas
Procedure NO-1-117, Rev. 11, Integrated risk management
Procedure RM-1-320, Rev. 0, Generation of the quarterly radiological effluent occurrence and reactor coolant system specific activity performance indicators
Procedure RM-1-322, Rev. 0, Occupational radiation safety performance indicator
Procedure RP-1-100, Rev. 6, Radiation Protection
Procedure RSP-1-104, Rev. 17, Area posting and barricading
Procedure RSP-1-106, Rev. 9, Special work permit administration
Procedure RSP-1-132, Rev. 8, Job coverage in radiologically controlled areas
Daily on-line dose report for February 2, 2004
SWP 2004-0119, Rev. 1, Rapid entry into RCAs for leak identification as approved by HP supervision/shift manager; Activity 1 - High Risk -Leak identification in containment at power
SWP 2004-0802, Rev. 0, Unit 1 forced outage; Activity 1 - Medium Risk - Maintenance in HRAs during a Unit 1 forced outage
SWP 2004-0804, Rev. 0, Unit 1 forced outage; Activity 1 - Low Risk - Maintenance in non-HRAs during a Unit 1 forced outage
Draft SWP 2004-0113 and ALARA review checklist for diving operations in the Unit 1 spent fuel pool
Health Physics shift turnover sheets for February 5, 2004
Health Physics program performance indicator panel #9, occupational exposure control effectiveness, December 2003
Trend analysis for radiological protection for fourth quarter of 2003

Letter from BG&E to USNRC dated March 15, 1995 and titled license amendment request

Section 2OS2, ALARA Planning and Controls:

Procedure RP-1-101, Rev. 3, ALARA
Procedure RSP-1-106, Rev. 9, Special work permit administration
Procedure RSP-1-200, Rev. 21, ALARA planning and SWP preparation
On-line ALARA dose targets for 2004
Outage ALARA dose targets for Unit 1 2004
Lists for SWPs for the 2004 On-line activities and for the Unit 1 refuel outage
Draft SWP 04-0113 and ALARA review checklist for diving operations in the Unit 1 spent fuel pool
ALARA committee charter, August 11, 2003
ALARA committee meeting minutes for December 2, 2003
ALARA committee meeting minutes for January 23, 2004
Draft Health Physics 2003 ALARA outage report
Health Physics high impact team plan, Rev. 1, Unit 1 refuel outage (2004)
Health Physics contingency plans for the Unit 1 2004 refuel outage
CCNPP 2004 refueling outage activity schedule for containment (April 9 through April 23, 2004)

Section 2OS3, Radiation Monitoring Instrumentation and Protective Equipment:

Procedure MN-2-101, Rev. 2, Control and calibration of radiation safety instrumentation
Procedure RSP-3-215, Rev. 1, Siemens electronic personal dosemeter calibration
Personnel unconditional release program refresher training, Rev. 1, January 2004

Section 4OA1: PI Verification

Calvert Cliffs Emergency Plan and Implementing Procedures

Section 4OA2: Identification and Resolution of Problems

Component Mispositionings

IR4-029-886: SGFP Portable Purifier Drain found open
IR4-031-143: Isolation of 1-CVC-501 from OPS
IR4-027-084: 12 Chg Pp Trip/13 Chg Pp Gas-Bind from Primary Eng
IR4-030-871: FW Heater Tube Side Drains found open
IR4-030-128: Inadvertent Trip of Channel ‘C’ of RPS
IR4-029-163: Control room HVAC Breaker found open
IR4-028-898: MWe loss due to extraction steam line drain...valves open
IR4-028-790: 21B Amertap placed in-svc w/out 22 CW Pp running
IR4-016-119: Cat I IR about unacceptable Mispositioning rate
IR4-0160119: RCAR and CA Plan for MisPo Rate
IR05000317/2003-009: NRC Inspection Report and NCV for MisPos

Flow Accelerated Corrosion (FAC) Program

IR4-013-246 Reheat Steam System, Piping Downstream of 1-FO-3710 below Specification
IR4-028-240 Corrective Actions to Flow Accelerated Corrosion Program
IR3-058-986 Identification of Pipe Replacement History
IR4-013-245 Resources for Implementation of Flow Accelerated Corrosion Program
Drawing: 91-474-B, Rev. 0, MS/R No.12 1st Stage Scavenging STM to Cold Reheat
Drawing: 60703SH0002, Rev. 16, Moisture Separator & Reheater Drains & Vents System

Miscellaneous Documents:

SA200200117	Self Assessment-Flow Accelerated Corrosion Programs
IR200300432	Action Item, Piping Degraded Below Code Min Wall
IR200300431	Action Item, Resources to Implement Flow Accelerated Program
1H200100036	Identify Areas of Pipe Replacement

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
ANS	Alert and Notification System
CAP	Corrective Action Program
CC	Component Cooling
CFR	Code of Federal Regulations
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
FAC	Flow Accelerated Corrosion
FAQ	Frequently Asked Question
HP	Health Physics
HIT	High Impact Team
HRA	High Radiation Area
HX	Heat Exchangers
IR	Issue Report
LER	Licensee Event Report
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NOED	Notice of Enforcement Discretion
OTF	Office Training Facility
PI	Performance Indicator
PI&R	Problem Identification and Resolution
RCA	Radiologically Controlled Area
RECO	Reasonable Expectation of Continued Operability
ROP	Reactor Oversight Process
RPS	Reactor Protection System
RSPS	Risk Significant Planning Standards
SBO	Station Blackout
SDP	Significance Determination Process

SG	Steam Generator
SIT	Special Inspection Team
SGFP	Steam Generator Feed Pump
SRW	Service Water
SW	Saltwater
SWP	Special Work Permit
TS	Technical Specifications
URI	Unresolved Item
VCT	Volume Control Tank
VHRA	Very High Radiation Area